federal register

THURSDAY, APRIL 1, 1976

PART VI:

FEDERAL POWER COMMISSION

■

NATURAL GAS

National Rates for Jurisdictional Sales

FEDERAL POWER COMMISSION

[Docket No. RM75-14]

NATIONAL RATES FOR JURISDICTIONAL SALES OF NATURAL GAS

Further Staff Rate Recommendations

MARCH 23, 1976.

By orders issued herein August 4, 1975 (40 FR 33860, 33998), and October 3, 1975 (40 FR 49139), the Commission issued Staff rate recommendations in this proceeding and provided, *inter alia*, for comment thereon by the parties. A number of comments were received, and the commenting procedure has terminated. Notice is given of other Staff rate recommendations, prepared by the Pipeline and Producer Rates Division of the Bureau of Natural Gas and attached hereto, which the Commission believes the parties should be given an opportunity to comment on. They do not supplant the previously issued recommendations, but are in addition thereto.

Comments on these additional rate recommendations may be filed with the Secretary of the Federal Power Commission, 825 North Capitol Street, NE., Washington, D.C. 20426, on or before April 23, 1976. Replies to such comments may be similarly filed on or before May 14, 1976. The procedures for filing such comments shall be as set forth in Ordering Paragraph (B) of the August 4, 1975 order issuing Staff rate recommendations, previously referred to.

The Secretary of the Commission shall publish this Notice in the FEDERAL REGISTER and shall serve it upon all participants in this proceeding, all State Commissions, all other Federal agencies and departments, and upon all parties of record in Docket No. R-389-B.

By direction of the Commission.

KENNETH F. PLUMB,
Secretary.

RESPONSE OF FEDERAL POWER COMMISSION STAFF

SUMMARY

The Commission's Order of December 4, 1974, in Docket No. RM75-14, entitled *Order Instituting National Rate Proceeding* calls on all parties to provide the facts, conditions, practices, and any other relevant matters pertaining to the sale of natural gas in interstate commerce, as well as a determination of the cost of finding and producing new supplies of natural gas, as set forth in ordering paragraph (B) of the Order.

In response, staff asserts that the nationwide cost of finding and producing new supplies of non-associated natural gas is 61.71 cents per Mcf at 14.73 psia and excluding production taxes. (See attached Appendix A). This cost was derived by using the discounted cash flow method adopted by the Commission in Opinion No. 699-H. A 15% rate of return on a discounted cash flow basis was employed which is the rate of return found reasonable by the Commission in Opinion No. 699-H issued December 4, 1974. Staff does not believe a re-evaluation of the 15% rate of return is necessary at this time because of the recent issuance of Opinion No. 699-H.

Staff concludes that producers finding new gas supplies will in fact realize, on average, a higher rate of return than 15% on new gas, because in many instances prices higher than staff's 61.71¢ cost are being paid for new supplies under intrastate contracts, emergency sales and to some extent under small producer certificates. Staff's average nationwide cost was estimated principally from published data which pertains to total cost and nonassociated gas reserve additions which may eventually be sold to either the interstate or intrastate market. In addition, generally lower cost flowing gas under expired contracts may be sold at the nationwide new gas rate. For these reasons gas producers will realize an average rate of return of at least 15% on all new gas supplies and this return therefore includes the necessary incentive to maintain the recent record levels of gas well drilling. Hopefully increases in gas reserve additions will result from this record drilling effort, which will improve the gas supply situation. However, Staff recognizes that interstate pipelines have bene unable to compete with intrastate buyers for new onshore gas supplies under current circumstances. There must be either total regulation or total deregulation of all new gas supplies offered for sale to permit interstate pipelines to effectively compete for long term supplies of onshore gas. Information for the 10 year period, 1964 through 1973, reveals that interstate pipelines have been experiencing a declining share of total gas reserve additions and year end reserves as follows:

Reserve additions, lower 48 States versus Interstate

Year	AGA reserve additions excluding revisions (thousand cubic feet)	Interstate new supply (form 15)	
		Thousand cubic feet	Percent
1964	NA	4.9	
1965	NA	10.4	
1966	14.8	10.0	68
1967	14.8	9.9	67
1968	9.8	6.4	65
1969	9.6	6.2	64
1970	11.3	3.5	31
1971	11.1	2.2	20
1972	10.7	5.0	47
1973	10.1	1.7	17

Yearend reserves, lower 48 States versus Interstate

Year	Total AGA reserves (thousand cubic feet)	Interstate reserves (form 15)	
		Thousand cubic feet	Percent
1964	276.5	189.2	68
1965	281.4	192.1	68
1966	283.2	195.1	69
1967	285.9	198.1	69
1968	278.6	195.0	70
1969	266.3	187.6	70
1970	255.6	173.6	68
1971	243.1	161.3	66
1972	230.2	146.9	64
1973	214.2	134.3	63

Staff believes the gas producing industry has been using vital resources such as drilling rigs, casing, tubing, etc. to the very limits of their availability. The gas industry has under lease over 300,000,000 nonproducing acres which should include a great number prospects possibly awaiting the availability of drilling rigs.

Staff contends that a price level approximating its cost estimate would achieve a maximum drilling effort by the industry and that any higher price level would do very little to benefit the interstate gas consumer. Due to higher prices for all types of hydrocarbon production the gas producing industry has greatly increased its gas well drilling activity in recent years with still greater improvements currently restricted by the aforementioned limits on available equipment. Consequently the industry is making the effort to ease the nation's gas supply problems but, unfortunately, the results achieved in terms of gas discoveries have not been encouraging.

APPENDIX A

ESTIMATED NATIONWIDE COST OF FINDING AND PRODUCING NEW SUPPLIES OF NON-ASSOCIATED GAS

General. Schedule No. 1, Sheet 1 of the attached cost study indicates several cost estimates which are shown for illustrative and comparative purposes. For reasons stated herein, Staff has determined a unit cost of 61.71¢ @ 14.73 psia shown in Column (e) as the cost reasonable estimate and recommends that the Commission adopt this cost for purposes of this rulemaking and biennial review for the period January 1, 1975, to December 31, 1976.

Columns (a) and (b) of Schedule No. 1, Sheet 1 were copied directly from Appendix C of Opinion No. 699-H and shown for comparative purposes.

Columns (c) and (d) of Schedule No. 1, Sheet 1 show cost estimates which were developed using the Permian methodology (Opinion No. 468) and recent available data. The difference in the total unit costs as shown in these two columns is attributable to the use of a productivity of 516 Mcf per foot (1947-1974, period) for the estimate shown in column (c) and 375 Mcf per foot (1966-1974, period) for the estimate shown in column (d). The main difference between the Commission's Permian and Opinion No. 699-H methods lies in the determination of the return allowance. The Permian method allowed a return on certain investment other than exploration over an average lag time and depletion life whereas the Opinion No. 699-H method employs the discounted cash flow method which in effect allows a return on total expenditures made to find and develop nonassociated gas.

The unit costs in columns (e) and (f) of Schedule No. 1, Sheet 1 were developed by using the Commission methods in Opinion No. 699-H. Column (e) reflects costs estimated from recent available data whereas column (f) reflects costs which were developed by trending. It should be noted that in following Commission methods, certain cost elements

such as productivity and expenditure relationships require informed judgment insofar as the time length of the data series to be used for averaging purposes. Staff based its cost estimates on data series which are longer than those used in Opinion No. 699–H. For example, expenditure relationships were averaged for the 1967–1973 period and productivity was estimated from data for the 1966–1974 period. These cost elements require a reevaluation of the data series in each instance when more recent data becomes available. Staff made this analysis and considers its estimates to be reasonable and consistent with the methods used in Opinion No. 699–H.

Staff is aware of the cost trending method adopted by the Commission in Opinion No. 699–H and therefore, for informational purposes, has trended drilling costs through the year 1975 with the resulting unit costs shown in column (f) of Schedule No. 1, Sheet 1. However, staff does not believe that costs can be trended with any certainty to levels are a forecast of the future because of the very unpredictable nature of the gas producing industry, and therefore selects the 61.71¢ determined in column (e) as its recommended cost. It should be noted that the industry in recent years has shifted much of their drilling to shallow, marginal, gas prospects because of higher gas prices. It is not known how long this phase will last but it is known that the industry has been holding under lease for many years over 300,000,000 nonproducing acres most of which is onshore. This may account for the decrease in gas well drilling costs per foot in recent years with an apparent decline in the productivity of the drilling. Staff has estimated productivity at 375 Mcf per foot, which is substantially lower than the 485 Mcf per foot used in Opinion No. 699–H and therefore results in a significantly higher unit cost. If the recent trend, towards shallower drilling reverses during the biennium (see Schedule No. 9) and the average depth of gas wells increases then the cost per foot will no doubt increase because of this factor and the pressures of inflation. For illustrative purposes, the 1973 cost per foot of gas wells was increased by 10% and the 1973 cost per foot of dry holes was increased by 12% and the resulting unit costs are shown in column (f) of Schedule No. 1, Sheet 1. These percentage increases are based upon annual averages of 5% and 6% for period 1963 through 1973. But as shown on Schedule No. 9, the percentage variation from year to year can be significant thus any trending is more a judgmental exercise rather than a mathematical or statistical problem. Further, if the Commission reviews the rates every two years in a timely fashion then there will be prompt compensation for unit cost increases. Staff, therefore, does not recommend trending for the short term.

Staff recommends the unit cost of 61.71¢ per Mcf shown in column (e) of Schedule No. 1, Sheet 1. This cost was determined by using the discounted cash flow method (DCF). The important factors employed were a 375 Mcf per foot productivity, a 15% rate of return, an 18 year depletion life, a 1½ year time lag, constant annual production rates and 1973 drilling costs without trending. It should be noted that if the Permian methodology (Opinion No. 468) were employed in place of the DCF method and all other cost factors remained the same, the resulting unit cost would be 53.98¢ per Mcf as shown in column (d) of Schedule No. 1, Sheet 1. The main difference lies in the unit return allowance which indicates a 6.5¢ increase using the DCF method. This is attributable to allowing a return on exploration expenditures.

The details indicating the cost computations for column (e) are shown on Sheets 4 and 5 with supporting Schedules 2 through 9. An explanation of the reasons staff employed certain cost factors as compared to those used by the Commission in Opinion No. 699–H are as follows:

Successful Well Cost. A gas well cost per foot of $27.43 per foot was used which is the 1973 drilling cost, excluding Alaskan data, as published by the Joint Association Survey (JAS). For reasons given previously, this cost was not trended and is the latest available figure.

A productivity of 375 Mcf of nonassociated gas reserves added per gas well foot drilled was considered reasonable for purposes of this cost study. This figure, as shown on Schedule No. 2, Sheet 1, reflects the weighted average of reserve additions and footage for the period 1966 through 1974. Averaging of data over a period of time is necessary in estimating productivity because many gas wells, particularly developmental wells, currently completed are related to reserve additions estimated and reported for prior years. The reason for this is based on a generally accepted fact that reserve additions estimated for earlier exploratory drilling are suspect in that complete reservoir characteristics are unknown at that time. Also, after full development of a gas reservoir, well performance data gathered over years may indicate changes in earlier initial reserve estimates. This necessitates using a long period for averaging purposes. However, the length of period which will yield the most reasonable result requires informed judgment. Staff arrived at the 9 year data period on this basis. The productivity of 375 Mcf per foot may be compared to the 485 Mcf per foot figure used in Opinion No. 699–H.

Recompletions & Deeper Drilling. Staff employed the amount 0.20¢ which is the same as that used in Opinion No. 699–H.

Lease Acquisition Costs. This unit cost is developed by determining the relationship of lease acquisition expenditures to total successful well expenditures and multiplying this fraction by the unit cost of gas wells. The fraction employed in Opinion No. 699–H was 0.6957 as compared to Staff's current estimate of 0.8680 (Schedule No. 3). The increase is due to large bonuses paid for Federal leases in recent years. Staff believes that the fraction should be derived from data which is averaged over a number of years even though this reduces the impact of higher lease costs paid in recent years. Since large Federal bonuses are paid in years before production commences and total gas reserves are estimated and reported by the AGA, it would therefore be improper and unreasonable to relate recent lease costs to recent well drilling costs and productivity. In addition, the productivity of gas well drilling on most Federal leases is significantly higher than the national average. These recent huge bonuses for Federal lease are being paid by the industry with the expectation of discovering large amounts of hydrocarbons. If this does not occur then it is inevitable that unit costs will rise substantially in the future.

Other Production Facilities. The fraction, 0.226, applied to the unit cost of gas wells, was employed in Opinion No. 699–H. Staff recalculated the fraction using Commission methods and the most recent available data in Docket No. R–478 and determined the fraction to be 0.232. The derivation of the fraction is shown on Schedule No. 4.

Dry Hole Costs. Similar to the gas well cost estimate, Staff used a dry hole cost of $18.93 per foot which is the 1973 cost, excluding Alaskan data, as published by the JAS. It is notable that the average depth of dry holes declined by 3.7% from 1973 to 1974 consistent with a 3.5% decline for gas wells during the same period (Schedule No. 9, Sheet 1). Should this shallower drilling trend prevail during the biennium drilling costs per foot may not increase even if inflation does not subside. The $18.93 per foot employed by staff may be compared to the $16.69 per foot used in Opinion No. 699–H.

Staff employed the fraction 0.84 (Schedule No. 6) which reflects the ratio of dry hole footage to gas well footage for the 1973–1974 period. The ratio of 1 to 1 was used in Opinion No. 699–H. The decline from 1.0 to 0.84 may be the result of advancements in seismic technology, specifically the so called "bright spot" method. Little is known of the method except that natural gas can be detected more easily than oil in the earth's subsurface prior to any drilling. Perhaps the industry should fully inform the Commission of the benefits of this method in exploring for natural gas. Certainly if this method is perfected it should reduce the incidence of dry holes in gas prospecting.

Other Exploration and Exploration Overhead. The fraction for other exploration was calculated at 0.5258 as compared to 0.6546 employed in Opinion No. 699–H. The fraction for exploration overhead was calculated at 0.1319 as compared to 0.1270 employed in Opinion No. 699–H. Staff's calculations were developed from data for the period, 1967–1973. Schedule No. 3 shows the computations and Schedule No. 1, Sheet 4 shows the resulting unit cost components.

Operating Expense. Schedule No. 5 shows the computation of the 3.10¢ per Mcf operating expense using the most recent available data obtained from the Rulemaking in Docket No. R–478. The

unit cost of 3.10¢ indicates no change has occurred as compared to the unit cost used in Opinion No. 699–H.

Unit Return on Investment. Schedule No. 1, Sheet 5 shows the underlying DCF calculation following specifically the methods employed by the Commission in Opinion No. 699–H. Staff is aware of the Tax Reduction Act of 1975 which repealed the percentage depletion allowance. However, as Staff interprets this law for regulated natural gas, the repeal does not become effective until July 1, 1976. Thus, most of the biennial period under investigation would not be subject to the effect of this new law. However, the next biennial review should consider the effect of this new tax law.

Return on Working Capital. Staff has updated the factors which account for materials, supplies and prepayments by employing the most recent available data from the Rulemaking in Docket No. R–478 (Schedule No. 7). In determining the unit return on working capital, Staff used the same formula employed in Opinion No. 699–H.

Regulatory Expense. Staff employed a unit expense of 0.10¢ in place of the 0.20¢ used in Opinion No. 699–H. The 0.10¢ is based upon more recent data available from the Rulemaking in Docket No. R–478.

Net Liquid Credit. Staff estimated liquid credit at 8:45¢ as compared to the 3.89¢ used in Opinion No. 699–H. The major change, which has occurred since the record was established in Docket No. R–389–B, is that the price of natural gas liquids has risen substantially as the result of the rising price of crude oil. The current average nationwide price of condensate and other natural gas liquids produced from recent gas wells as not available. However, Staff has reviewed publications of the U.S. Bureau of Mines and industry trade journals and reasonably, but conservatively, estimates the price of new condensate at $10 per barrel and other plant liquids at 7¢ per gallon. The Oil and Gas Journal (March 24, 1975 issue) reported that the price of exempt crude and in some instances condensate has hit $12 per barrel. However, prices at this level may be temporary and Staff prefers the use of $10 per barrel which appears to have been applicable for most of the year 1974.

In reference to other natural gas liquids, U.S. Bureau of Mines' data indicate an average price of 6.9¢ per gallon for the year 1973. Staff used 7¢ per gallon which approximates the BOM figure. It is very probable that the current price greatly exceeds the 7¢ figure, however, information is unavailable.

The calculations and sources of the other data underlying the liquid credit estimate are shown on Schedule No. 8, Sheets 1 and 2.

Royalty at 16%. Staff calculated royalty on the basis of 16% which is the figure used in Opinion No. 699–H. Current information is unavailable to update the 16% royalty.

Estimated Nation-wide Cost of Finding and Producing Non-Associated Gas
Cents Per Mcf at 14.73 psia

Line No.	Cost Component	Opinion No. 699-H 1972 Data (a)	Opinion No. 699-H Trended Data (b)	Permian Methodology Opinion No. 468 (c)1/	Permian Methodology Opinion No. 468 (d)2/	DCF Method Opinion No. 699-H Current (e)2/	DCF Method Opinion No. 699-H Trended (f)2/
1.	Successful Wells	5.68	6.15	5.32	7.31	7.31	8.05
2.	Recompletions, etc.	0.20	0.20	0.20	0.20	0.20	0.20
3.	Lease Acquisition	3.83	4.28	4.62	6.35	6.35	6.99
4.	Other Production Facilities	1.28	1.39	1.23	1.70	1.70	1.87
5.	Subtotal	10.99	12.02	11.37	15.56	15.56	17.11
6.	Dry Holes	3.77	3.72	3.33	4.58	4.58	5.13
7.	Other Exploration	2.62	2.80	2.43	3.34	3.34	3.68
8.	Exploration Overhead	0.82	0.82	0.76	1.04	1.04	1.16
9.	Subtotal	7.21	7.34	6.52	8.96	8.96	9.97
10.	Operating Expense	3.10	3.10	3.10	3.10	3.10	3.10
11.	Return @15%	21.42	23.21	17.75	24.35	30.85	34.48
12.	Return on Working Capital	1.14	1.25	1.27	1.72	1.72	1.88
13.	Net Liquid Credit	(3.89)	(3.89)	(8.45)	(8.45)	(8.45)	(8.45)
14.	Regulatory Expense	0.20	0.20	0.10	0.10	0.10	0.10
15.	Subtotal	40.17	43.23	31.66	45.34	51.84	58.19
16.	Royalty @16%	7.65	8.23	6.03	8.64	9.87	11.08
17.	Total @14.73 psia	47.82	51.46	37.69	53.98	61.71	69.27

1/ Productivity at 516, 1947 - 1974
2/ Productivity at 375, 1966 - 1974

Columns (c) through (f); the unit cost computations are shown on Sheets 2-7.

Schedule No. 1
Sheet 2 of 7

Cost Computations (Source)
(Refer to Column (c) of Sheet 1)

Line No.	
1.	5.32 = $27.43/ft. (1973 JAS) ÷ 516 Mcf/ft. (Schedule No. 2)
2.	0.20 = Opinion No. 662
3.	4.62 = 5.32 (Line 1) x 0.868 (Schedule No. 3)
4.	1.23 = 5.32 (Line 1) x 0.232 (Schedule No. 4)
5.	11.37 = Sum of Lines 1-4
6.	3.33 = $18.93/ft. (1973 JAS) x 1.08 (Opinion No. 662) ÷ 516 Mcf/ft. x 0.84 (Schedule No. 6)
7.	2.43 = 4.62 (Line 3) x 0.5258 (Schedule No. 3)
8.	0.76 = 5.76 (Line 6 + 7) x 0.1319 (Schedule No. 3)
9.	6.52 = Sum of Lines 6-8
10.	3.10 = Schedule No. 5
11.	17.75 = [11.37 (Line 5) - 1/2 x 0.20 (Line 2)] x 10.5 x 0.15
12.	1.27 = [6.52 (Line 9) x 1/8 x 1.21 (Schedule 7) + 3.10 (Line 10) x 1/8 x 1.48 (Schedule 7) + 4.62 (Line 3) x 1.5] x 0.15
13.	(8.45) = Schedule No. 8
14.	0.10 = Docket No. R-478
15.	31.66 = Sum of Lines 5, 9, 10-14
16.	6.03 = Royalty at 16%
17.	37.69 = Sum of Lines 15 and 16

Cost Computations (Source)
(Refer to Column (d) of Sheet 1)

Line No.		
1.	7.31	= $27.43/ft. (1973 JAS) ÷ 375 Mcf/ft. (Schedule No. 2)
2.	0.20	= Opinion No. 662
3.	6.35	= 7.31 (Line 1) x 0.868 (Schedule No. 3)
4.	1.70	= 7.31 (Line 1) x 0.232 (Schedule No. 4)
5.	15.56	= Sum of Lines 1-4
6.	4.58	= $18.93/ft. (1973 JAS) x 1.08 (Opinion No. 662) ÷ 375 Mcf/ft. (Schedule No. 2) x 0.84 (Schedule No. 6)
7.	3.34	= 6.35 (Line 3) x 0.5258 (Schedule No. 3)
8.	1.04	= 7.92 (Line 6 + 7) x 0.1319 (Schedule No. 3)
9.	8.96	= Sum of Lines 6-8
10.	3.10	= Schedule No. 5
11.	24.35	= [15.56 (Line 5) - 1/2 x 0.20 (Line 2)] x 10.5 x 0.15
12.	1.72	= [8.96 (Line 9) x 1/8 x 1.21 (Schedule 7) + 3.10 (Line 10) x 1/8 x 1.48 (Schedule 7) + 6.35 (Line 3) x 1.5] x 0.15
13.	(8.45)	= Schedule No. 8
14.	0.10	= Docket No. R-478
15.	45.35	= Sum of Lines 5, 9, 10-14
16.	8.64	= Royalty at 16%
17.	53.98	= Sum of Lines 15 and 16

Schedule No. 1
Sheet 4 of 7

Cost Computations (Source)
(Refer to Column (e) of Sheet 1)

Line No.	
1.	7.31 = $27.43/ft. (1973 JAS) ÷ 375 Mcf/ft. (Schedule No. 2)
2.	0.20 = Opinion No. 662
3.	6.35 = 7.31 (Line 1) x 0.868 (Schedule No. 3)
4.	1.70 = 7.31 (Line 1) x 0.232 (Schedule No. 4)
5.	15.56 = Sum of Lines 1-4
6.	4.58 = $18.93/ft. (1973 JAS) x 1.08 (Opinion No. 662) ÷ 375 Mcf/ft. (Schedule No. 2) x 0.84 (Schedule No. 6)
7.	3.34 = 6.35 (Line 3) x 0.5258 (Schedule No. 3)
8.	1.04 = 7.92 (Line 6 + 7) x 0.1319 (Schedule No. 3)
9.	8.96 = Sum of Lines 6-8
10.	3.10 = Schedule No. 5
11.	30.85 = Result of DCF method (Schedule No. 1, Sheet 5)
12.	1.72 = /8.96 (Line 9) x 1/8 x 1.21 (Schedule 7) + 3.10 (Line 10) x 1/8 x 1.48 (Schedule 7) + 6.35 (Line 3) x 1.57 x 0.15
13.	(8.45)= Schedule No. 8
14.	0.10 = Docket No. R-478
15.	51.84 = Line 17-16
16.	9.87 = 16% of Line 17
17.	61.71 = Schedule No. 1, Sheet 5

Computation of Price by the
DCf Method Used in Opinion No. 699-H
(Refer to Column (e) of Sheet 1)

Line No.	Pre-production Expenses (1)	Year (2)	Value (3)	Percent Expensed (4)	Percent Tax Rate (5)	Tax Credit (6)	Net Investment (7)	Compound Interest Factor (8)	Present Value (9)
1.	Other Exploration	3	3.34	95	48	1.5230	1.8170	1.5209	2.7635
2.	Exploration Overhead	3	1.04	95	48	0.4742	0.5658	1.5209	0.8605
3.	Lease Acquisition	2	6.35	0	0	0	6.35	1.3225	8.3979
4.	Dry Holes	1	4.58	100	48	2.1984	2.3816	1.15	2.7388
5.	Successful Wells	1	7.51	70	48	2.5234	4.9866	1.15	5.7346
6.	Production Facilities	1	1.70	0	0	0	1.70	1.15	1.9550
7.	Lease Acquisition Credit	1	--	75	48	2.286	-2.286	1.15	-2.6289
8.	Total		24.52			9.005			19.8214

	Net Cash Flow	Amount
9.	Price	X
10.	Royalty	-0.16X
11.	Operating Expense	-3.10
12.	Interest on Working Capital	-1.72
13.	Regulatory Expense	-0.10
14.	Tax Liability to Offset Tax Credit	-9.005
15.	Liquid Credit	+8.45
16.	Total	0.84X -5.475

17. $19.8214 = (0.84 X -5.475) \times 1/18 \times 7.047 + 0.84 \times 1/18 \times 35.829965$

18. Price = X = 61.71¢/Mcf

Sources:

Investment and Expenses are from Schedule No. 1, Sheet 1, Column (e).
All other factors are from Opinion No. 699-H.

Schedule No. 1
Sheet 6 of 7

Cost Computations (Source)
(Refer to Column (f) of Sheet 1)

Line No.	
1.	8.05 = $30.17/ft. (1973 JAS Trended to 1975) ÷ 375 Mcf/ft. (Schedule No. 2)
2.	0.20 = Opinion No. 662
3.	6.99 = 8.05 (Line 1) x 0.868 (Schedule No. 3)
4.	1.87 = 8.05 (Line 1) x 0.232 (Schedule No. 4)
5.	17.11 = Sum of Lines 1-4
6.	5.13 = $21.20/ft. (1973 JAS Trended to 1975) x 1.08 (Opinion No. 622 ÷ 375 Mcf/ft. x 0.84 (Schedule No. 6)
7.	3.68 = 6.99 (Line 3) x 0.5258 (Schedule No. 3)
8.	1.16 = 8.81 (Line 6 + 7) x 0.1319 (Schedule No. 3)
9.	9.97 = Sum of Lines 6-8
10.	3.10 = Schedule No. 5
11.	34.48 = Result of DCF method (Schedule No. 1, Sheet 7)
12.	1.88 = [9.97 (Line 9) x 1/8 x 1.21 (Schedule 7) + 3.10 (Line 10)] x 1/8 x 1.48 (Schedule 7) + 6.99 (Line 3) x 1.57 x 0.15
13.	(8.45)= Schedule No. 8
14.	0.10 = Docket No. R-478
15.	58.19 = Line 16-17
16.	11.08 = 16% of Line 17
17.	69.27 = Schedule No. 1, Sheet 7

Computation of Price by the
DCF Method Used in Opinion No. 699-H
(Refer to Column (f) of Sheet 1)

Line No.	Pre-production Expenses (1)	Year (2)	Value (3)	Percent Expensed (4)	Percent Tax Rate (5)	Tax Credit (6)	Net Investment (7)	Compound Interest Factor (8)	Present Value (9)
1.	Other Exploration	3	3.68	95	48	1.6780	2.002	1.5209	3.0448
2.	Exploration Overhead	3	1.16	95	48	0.5290	0.6310	1.5209	0.9597
3.	Lease Acquisition	2	6.99	0	0	0	6.99	1.3225	9.2443
4.	Dry Holes	1	5.13	100	48	2.4624	2.6676	1.15	3.0677
5.	Successful Wells	1	8.25	70	48	2.7720	5.4780	1.15	6.2997
6.	Production Facilities	1	1.87	0	0	0	1.87	1.15	2.1505
7.	Lease Acquisition Credit	1	--	75	48	2.5164	-2.5164	1.15	-2.8939
8.	Total		27.08			9.9578			21.8728

	Net Cash Flow	Amount
9.	Price	x
10.	Royalty	-0.16x
11.	Operating Expense	-3.10
12.	Interest on Working Capital	-1.88
13.	Regulatory Expense	-0.10
14.	Tax Liability to Offset Tax Credit	-9.9578
15.	Liquid Credit	+8.45
16.	Total	0.84 x -6.5878

Solving For Price

17. $21.8728 = (0.84 \times -6.5878) \times 1/18 \times 7.047 + 0.84 \times 1/18 \times 35.829965$

18. Price = x = 69.27¢/Mcf

Sources:

Investment and Expenses are from Schedule No. 1, Column (f).
All other factors are from Opinion No. 699-H.

Schedule No. 2
Sheet 1 of 3

Productivity Estimates

AGA and API-AAPG Data

Time Period	Reserve Additions (Bcf)	Footage (Mft.)	Productivity
1970-1974, 5 yrs.	35,916	146,766	245
1969-1974, 6 yrs.	42,791	170,830	250
1968-1974, 7 yrs.	55,126	190,949	289
1967-1974, 8 yrs.	72,409	211,738	342
1966-1974, 9 yrs.	88,545	236,128	375

AGA and World Oil Data

Time Period	Reserve Additions (Bcf)	Footage (Mft.)	Productivity
1970-1974, 5 yrs.	35,916	138,823	259
1969-1974, 6 yrs.	42,791	160,468	267
1968-1974, 7 yrs.	55,126	180,557	305
1967-1974, 8 yrs.	72,409	201,997	358
1966-1974, 9 yrs.	88,545	227,597	389
1965-1974, 10 yrs.	106,839	252,451	423
1960-1974, 15 yrs.	180,365	388,924	464
1955-1974, 20 yrs.	256,680	507,229	506
1947-1974, 28 yrs.	325,254	629,779	516

AGA (Excluding Revisions) and API-AAPG Data

Time Period	Reserve Additions (Bcf)	Footage (Mft.)	Productivity
1970-1974, 5 yrs.	46,764	146,766	319
1969-1974, 6 yrs.	55,079	170,830	322
1968-1974, 7 yrs.	63,377	190,949	332
1967-1974, 8 yrs.	76,948	211,738	363
1966-1974, 9 yrs.	90,027	236,128	381

NON-ASSOCIATED GAS RESERVES ADDITIONS
PER GAS WELL FOOT DRILLED
UNITED STATES EXCLUDING ALASKA
1947 - 1974

Year	AGA Reserves Added (Bcf at 14.73 psia) (1)	Reserves Added With Revisions Excluded (1-A)	World Oil Footage (M Feet) (2)	AAPG-API Footage (M Feet) (3)	Productivity (Mcf/ft) (Col. 1 ÷ Col. 2) (4)	Productivity (Mcf/ft) (Col. 1 ÷ Col. 3) (5)	Productivity (Mcf/ft) (Col. 1-A ÷ Col. 3) (6)
1947	6,527	--	13,249	--	485	--	--
1948	7,444	--	12,500	--	596	--	--
1949	6,809	--	12,860	--	529	--	--
1950	9,016	--	14,003	--	644	--	--
1951	8,424	--	14,508	--	581	--	--
1952	9,569	--	16,070	--	595	--	--
1953	15,284	--	19,473	--	785	--	--
1954	5,601	--	19,887	--	282	--	--
1955	12,678	--	19,589	--	647	--	--
1956	15,222	--	22,593	--	674	--	--
1957	16,119	--	24,226	--	665	--	--
1958	17,294	--	25,385	--	681	--	--
1959	15,002	--	26,512	--	566	--	--
1960	11,449	--	28,215	--	406	--	--
1961	14,307	--	29,256	--	489	--	--
1962	17,253	--	28,921	--	597	--	--
1963	13,274	--	24,495	--	542	--	--
1964	17,243	--	25,586	--	674	--	--
1965	18,294	1/	24,854	1/	736	1/	1/
1966	16,136	13,079	25,600	24,390	630	662	536
1967	17,283	13,571	21,440	20,789	806	831	653
1968	12,335	8,298	20,089	20,119	614	613	412
1969	6,875	8,314	21,645	24,064	318	286	346
1970	9,351	9,641	19,806	22,852	472	409	422
1971	8,565	10,037	20,042	22,609	427	379	444
1972	7,597	9,508	26,571	26,743	286	284	355
1973	3,717	9,064	32,974	35,587	113	104	254
1974	6,686	8,514	39,430	38,975	170	172	218

1/ Data unavailable prior to 1966.

Schedule No. 2
Sheet 3 of 3

American Gas Association *
Non-Associated Gas Reserves
MMCF @ 14.73 psia

United States (Excludes Alaskan Data)

Year	Revisions (a)	Extensions (b)	New Field (c)	New Reservoir (d)	Total 1/ (e)
1966	3,056,812	7,490,746	2,813,222	2,775,360	16,136,140
1967	3,712,892	8,625,273	2,819,635	2,126,298	17,284,098
1968	4,036,210	5,864,521	1,206,628	1,227,600	12,334,959
1969	(1,440,196)	4,788,627	1,663,266	1,863,021	6,874,718
1970	(290,034)	4,886,132	1,556,494	3,198,724	9,351,316
1971	(1,471,410)	5,625,841	1,176,939	3,234,033	8,565,403
1972	(1,911,097)	5,449,052	1,264,756	2,794,559	7,597,270
1973	(5,347,021)	5,305,857	1,968,520	1,789,574	3,716,930
1974	(1,828,794)	4,941,208	1,755,214	1,817,877	6,685,505

1/ These totals equal the summation of Columns (a) through (d). The parentheses () in Column (a) denote negative amounts.

*/ Reserves Of Crude Oil, Natural Gas Liquids, And Natural Gas In The United States And Canada And United States Productive Capacity As Of December 31, 1972, Volume 27, Published Jointly by the American Gas Association, American Petroleum Institute, and the Canadian Petroleum Institute (May 1973).

Estimated Expenditures for Findings and Developing Gas and Oil in the United States, 1967 - 1973 (Millions of Dollars)

Line No. (a)	Year (b)	Cost of Producing Wells (c)	Dry Hole Cost (d)	Lease Acquisition Cost (e)	Exploratory Overhead (f)	Other Exploratory Costs (g)
1.	1967	1,497	802	829	206	740
2.	1968	1,583	826	1,578	204	770
3.	1969	1,723	888	1,137	210	782
4.	1970	1,706	873	714	189	728
5.	1971	1,508	864	642	206	746
6.	1972	1,807	1,006	1,722	239	766
7.	1973	2,005	1,070	3,646	293	867
8.	1967-1972	9,824	5,259	6,622	1,254	4,532
9.	1967-1973	11,829	6,329	10,268	1,547	5,399

10. Lease Acquisition Costs as a Fraction of Successful Well Cost = 6,622 ÷ 9,824 = 0.6741 (1967-1972); 10,268 ÷ 11,829 = 0.8680 (1967-1973)

11. Other Exploratory Costs as a Fraction of Lease Acquisition Costs = 4,532 ÷ 6,622 = 0.6844 (1967 - 1972); 5,399 ÷ 10,268 = 0.5258 (1967 - 1973).

12. Exploratory Overhead as a Fraction of Dry Hole and Other Exploratory Costs = 1,254 ÷ 9,791 = 0.1281 (1967 -1972); 1,547 ÷ 11,728 = 0.1319 (1967 - 1973).

Source: Joint Association Survey of the U. S. Oil & Gas Producing Industry, Section I and Section II.

Schedule No. 4

Calculation Of The Factor To Determine The Cost Of Other Production Facilities Using 1972 Data Filed In Docket No. R-478 By Independent Producers And Pipeline Affiliates

Line No.	Item	Investment (Dollars in Thousands)
1)	Lease & Well Equipment Cost	1,618,853
2)	Lease Equipment Cost Fraction of Lease and Well Equipment Cost	0.281
3)	Lease Equipment Cost (Line 1 x 2)	454,898
4)	Well Equipment Cost (Line 1 - 3)	1,163,955
5)	Intangible Development Costs	3,232,043
6)	Successful Well Costs (Line 4 + 5)	4,395,998
7)	Related Producing Facilities	330,440
8)	Production Buildings, Facilities etc.	70,848
9)	Other Production Facilities (Lines 3 + 7 + 8)	859,186
10)	Other Production Facilities Fraction of Successful Well Cost (Line 9 ÷ 6)	0.195
11)	Corporate General, Area, District etc. (Net)	84,085
12)	Investment Overhead (Line 11) Fraction of Successful Well Costs (Line 6 on Net Basis)	0.037
13)	Total Other Production Facilities Fraction of Successful Well Costs (Line 10 + 12)	0.232

Sources: Lines 1, 5, 7, 8 and 11; Data Composites Submitted by Letter of Feb. 13, 1974 to all parties in Docket No. R-478. The Data relate to gas leases. Overheads were allocated to gas leases on the basis of Gross Investment.

Line 2; Docket No. AR69-1, Exhibit #80, Sch. 4

Line 12; Line 11 ÷ Line 6 x 0.515. The factor 0.515 is the ratio of Net Investment to Gross Investment for IDC and lease and well equipment.

Schedule No. 5

Calculation Of Unit Production Operating Expense Using 1972 Data Filed In Docket No. R-478 By Independent Producers And Pipeline Affiliates

Line No.	Item	Expense (Dollars in Thousands)
1)	Lease Operating Expense	233,485
2)	Corporate General, Area, District etc. Expense	59,043
3)	Miscellaneous Lease Revenue	4,237
4)	Total Expense (Line 1 + 2) Minus Line 3	288,291
5)	Unit Expense (Line 4 ÷ 8,510 Bcf, Gas Well Gas Production) = 3.39¢/Mcf	
6)	Adjustment From Gross Wet To Net Dry Production (1.0873 x 3.39¢ = 3.69¢)	
7)	Conversion From Working Interest To 100% (3.69¢ x 0.84 = 3.10¢/Mcf)	
8)	Final Unit Cost = 3.10¢/Mcf	

Source: Lines 1, 2, 3 & 5; Data Composites submitted by letter of Feb. 13, 1974 to all parties in Docket No. R-478. Overheads (Line 2) were allocated to gas leases on the basis of direct expenses.

Line 6, the factor of 1.0873 was calculated by dividing gross wet production, 19372 Bcf (1973 Bureau of Mines) by net dry production 17816 Bcf (1973 AGA)

Line 7, the factor of 0.84 (1.00 - .16) is based on royalty of 16%

Schedule No. 6
Sheet 1 of 2

Allocation of Dry Hole Footage to Gas Well Footage 1/
Year - 1974

Line No.		Successful Exploratory Footage (1)	% of Total (2)	Exploratory Dry Hole Footage (3)	Allocated Footage (4)	
1.	Gas	7,665	61.3%		23,091	(Col. (2) Line 1 x Col. (3) Line 3)
2.	Oil	4,833	38.7%		14,578	(Col. (2) Line 2 x Col. (3) Line 3)
3.	Total	12,498	100.0%	37,669	37,669	(Line 1 + 2)
		Successful Developmental Footage (1)	% of Total (2)	Develop. Dry Hole Footage (3)	Allocated Footage (4)	
4.	Gas	31,311	40.9%		9,661	(Col. (2) Line 4 x Col. (3) Line 6)
5.	Oil	45,179	59.1%		13,959	(Col. (2) Line 5 x Col. (3) Line 6)
6.	Total	76,490	100.0%	23,620	23,620	(Line 4 + 5)
		Total Successful Footage (1)	Allocated Dry Hole Footage (2)	Dry Hole Factor (3)		
7.	Gas	38,975	32,752	0.84		(Col. (2) Line 7 ÷ Col. (1) Line 7)
8.	Oil	50,012	28,537	0.57		(Col. (2) Line 8 ÷ Col. (1) Line 8)
9.	Total	88,987	61,289			

Sources and Notes:

1/ Footage in 1000 feet and exclude Alaskan Data. Source; API-AAPG.

Allocation of Dry Hole Footage to Gas Well Footage 1/
Year - 1973

Line No.		Successful Exploratory Footage (1)	% of Total (2)	Exploratory Dry Hole Footage (3)	Allocated Footage (4)	
1.	Gas	6,166	61.7%		21,380	(Col. (2) Line 1 x Col. (3) Line 3)
2.	Oil	3,828	38.3%		13,272	(Col. (2) Line 2 x Col. (3) Line 3)
3.	Total	9,994	100%	34,652	34,652	
4.	Gas	29,421	42%		88,987	(Col. (2) Line 4 x Col. (3) Line 6)
5.	Oil	40,605	58%		12,410	(Col. (2) Line 5 x Col. (3) Line 6)
6.	Total	70,026	100%	21,397	21,397	

		Total Successful Footage (1)	Allocated Dry Hole Footage (2)	Dry Hole Factor (3)	
7.	Gas	35,587	30,367	0.85	(Col. (2) Line 7 ÷ Col. (1) Line 7)
8.	Oil	44,434	25,682	0.58	(Col. (2) Line 8 ÷ Col. (1) Line 8)
9.	Total	80,021	56,049		

Sources and Notes:

1/ Footage in 1000 feet and exclude Alaskan Data. Source; API-AAPG.

Schedule No. 7

Derivation of Factor for Materials, Supplies and Prepayments in Calculating Working Capital Allowance

Line No.	Exploration Expense	
1.	1/8 of E&D Expenditures	$141,298,689
2.	Materials, Supplies and Prepayments	29,003,899
3.	Total	$170,302,588
4.	Factor (Line 3 ÷ Line 1) = 1.21	
	Production Expense	
5.	1/8 of Production Expense	$ 36,036,389
6.	Materials, Supplies and Prepayments	17,215,535
7.	Total	$ 53,252,924
8.	Factor (Line 7 ÷ Line 5) = 1.48	

Source:

Notice Issuing Staff Rate Recommendations and Prescribing Procedures in Docket No. R-478 dated September 12, 1974. Composite data for Independent Producers and Pipeline Affiliates.

Liquid Credit Estimate

	Amount	Unit	Source or Computation
Liquid to Gas Ratios			
1. Lease Condensate	8.69	bbl/mmcf	Sheet 2, Schedule No. 8
2. Plant Condensate	1.11	bbl/mmcf	Sheet 2, Schedule No. 8
3. Other Plant Liquids	0.694	gal/mcf	Sheet 2, Schedule No. 8
Gross Unit Revenue			
4. Lease Condensate	10	$/bbl	Staff Estimate
5. Plant Condensate	10	$/bbl	Staff Estimate
6. Other Plant Liquids	7	¢/gal	Staff Estimate
Liquid Credit Components			
7. Lease Condensate	6.88	¢/mcf	8.69(line 1)x10(line 4)x0.1(¢/mcf) x .943 1/ x .84 2/
8. Plant Condensate	0.84	¢/mcf	1.11(line 2)x10(line 5)x0.1(¢/mcf) x .95 3/x .943 1/x .84 2/
9. Other Plant Liquids	0.73	¢/mcf	(0.694(line 3)x7(line 6)x .34 4/ - .74 5/) x .96 6/x .84 2/
10. Total Liquid Credit	8.45	¢/mcf	Sum of Lines 7, 8, and 9.

Notes:

1/ Factor to Reduce Condensate Revenue by Production Tax of 5.7%
2/ Factor to Reduce Condensate Revenue by Royalty paid at 16%
3/ Lease Share of Plant Condensate Revenue
4/ Lease Share of Other Plant Liquid Revenue
5/ Estimated Value of Fuel Consumed in Gas Processing Plants
6/ Factor to Reduce Other Plant Liquid Revenue by Production Tax of 4%

Schedule No. 8
Sheet 2 of 2

Computation of Liquid to Gas Ratios For Non-Associated Gas Production

	Unit	1970	1971	1972	1973	1974
1. Non-Associated (NA) Gas Liquids	1000bbls	487,536	486,159	481,799	468,979	1/
2. Lease Condensate	1000bbls	166,784	157,302	155,931	154,891	143,234(p)
3. NA Plant Liquids (Line 1-2)	1000bbls	320,752	328,857	325,868	314,088	1/
4. Plant Condensate	1000bbls	31,972	25,754	22,022	19,838	17,733(p)
5. NA Plant Extracted Liquids (line 3 - 4)	1000bbls	288,780	303,103	303,846	294,250	1/
6. NA Gas Production @ 14.73 psia	Bcf	17,043	17,233	17,693	17,816	17,091(p)
7. Liquid To Gas Ratios						
A. Lease Condensate (Line 2 ÷ 6)	bbl/mmcf	9.78	9.12	8.81	8.69	8.38
B. Plant Condensate (line 4 ÷ 6)	bbl/mmcf	1.78	1.49	1.24	1.11	1.04
C. Plant Extracted Liquids (Line 5 ÷ 6)	bbl/mmcf	16.94	17.58	17.17	16.52	1/
D. Plant Extracted Liquids (GPM)	gal/mcf	.712	.738	.721	.694	1/

Sources and Notes:

(p) Preliminary

1/ Data will be available in June of 1975 (AGA)
Lines 1 and 6; American Gas Association (AGA)
Lines 2 and 4; Bureau of Mines (BOM)

Drilling Cost and Depth Trends

Drilling Costs
1963 Through 1973

Year	Gas Well Cost $ Per Foot	Gas Well Cost % Increase Or Decrease	Dry Hole Cost $ Per Foot	Dry Hole Cost % Increase Or Decrease
1963	17.11	--	10.42	--
1964	18.10	+ 5.8	10.54	+ 1.2
1965	18.16	+ 0.3	11.16	+ 5.9
1966	21.60	+18.9	12.00	+ 7.5
1967	22.90	+ 6.0	12.14	+ 1.2
1968	23.69	+ 3.4	12.60	+ 3.8
1969	24.35	+ 2.8	12.78	+ 1.4
1970	26.62	+ 9.3	14.33	+12.1
1971	27.63	+ 3.8	15.83	+10.5
1972	27.53	- 0.4	16.94	+ 7.0
1973	27.43	- 0.4	18.93	+11.7
Average Annual		+ 5.0		+ 6.2

Average Drilling Depth

Year	Gas Wells	% Increase Or Decrease	Dry Holes	% Increase Or Increase	Oil Wells	% Increase Or Decrease
1967	5,871	--	4,602	--	3,809	--
1968	5,992	+ 1.7	5,046	+ 9.6	4,116	+ 8.1
1969	5,910	- 1.4	5,192	+ 2.9	4,266	+ 2.7
1970	5,959	+ 0.8	5,246	+ 1.0	4,353	+ 2.0
1971	5,905	- 0.9	5,220	- 0.5	4,080	- 6.7
1972	5,429	- 8.8	5,360	+ 2.7	4,287	+ 5.1
1973	5,576	+ 2.7	5,445	+ 1.6	4,496	+ 4.9
1974	5,386	- 3.5	5,253	- 3.7	3,920	-14.7

TOTAL UNITED STATES 1/
COMPARISON OF ANNUAL DRILLING STATISTICS
Calendar Years 1970-1974

Line No.		Wells					Footage (thousands of feet)					Average Depth (feet)				
		1970	1971	1972	1973	1974	1970	1971	1972	1973	1974	1970	1971	1972	1973	1974
1.	Total Wells Drilled 2/															
2.	Oil Wells	12,953	11,831	11,294	9,882	12,757	56,389	48,269	48,413	44,434	50,012	4,353	4,080	4,287	4,496	3,920
3.	Gas Wells	3,835	3,329	4,926	6,382	7,237	22,852	22,609	26,743	35,587	38,975	5,959	5,905	5,429	5,576	5,386
4.	Dry Holes	11,220	10,159	11,045	10,294	11,667	58,865	53,027	59,201	56,050	61,289	5,246	5,220	5,360	5,445	5,253
5.	Total Wells	28,008	25,819	27,265	26,558	31,661	138,106	123,904	134,356	136,069	150,276	4,931	4,799	4,928	5,123	4,746
6.	Development Wells															
7.	Oil Wells	12,186	11,181	10,610	9,265	11,945	51,570	44,566	44,411	40,605	45,179	4,232	3,986	4,196	4,383	3,782
8.	Gas Wells	3,355	3,392	4,326	5,483	6,044	19,187	19,280	22,166	29,421	31,311	5,719	5,648	5,124	5,366	5,181
9.	Dry Holes	4,834	4,329	4,803	4,358	5,064	22,727	19,717	22,853	21,397	23,620	4,702	4,555	4,758	4,910	4,664
10.	Total Wells	20,375	18,902	19,739	19,106	23,053	93,485	83,563	89,431	91,423	100,110	4,588	4,421	4,531	4,785	4,343
11.	Total Exploratory Wells 3/															
12.	Oil Wells	767	650	684	617	812	4,818	3,702	4,002	3,828	4,833	6,282	5,695	5,850	6,205	5,952
13.	Gas Wells	480	437	600	899	1,192	3,665	3,328	4,576	6,166	7,665	7,635	7,616	7,627	6,859	6,430
14.	Dry Holes	6,386	5,830	6,242	5,936	6,603	36,138	33,310	36,348	34,652	37,669	5,659	5,714	5,823	5,838	5,705
15.	Total Wells	7,633	6,917	7,526	7,452	8,607	44,621	40,341	44,925	44,646	50,167	5,846	5,832	5,969	5,991	5,829

1/ Excludes Alaska and all service wells and stratigraphic and core tests
2/ Development wells plus total exploratory wells.
3/ New-field wildcat wells plus other exploratory wells (new-pool wildcats, deeper-pool tests, shallower-pool tests and outpost or extension tests).

Source: Quarterly Review of Drilling Statistics for the United States; American Petroleum Institute.

VERIFICATION

Lundy R. Wright, Jr., being first duly sworn, deposes and says that he is Chief of the Pipeline and Producer Rates Division, Bureau of Natural Gas of the Federal Power Commission, that he is authorized to verify and file this document which was prepared by the Pipeline and Producer Rates Division on or about May 12, 1975, that he has examined the statements contained in the "Response of Federal Power Commission Staff" in Docket No. RM75-14 and that all such statements are true and correct to the best of his knowledge, information and belief.

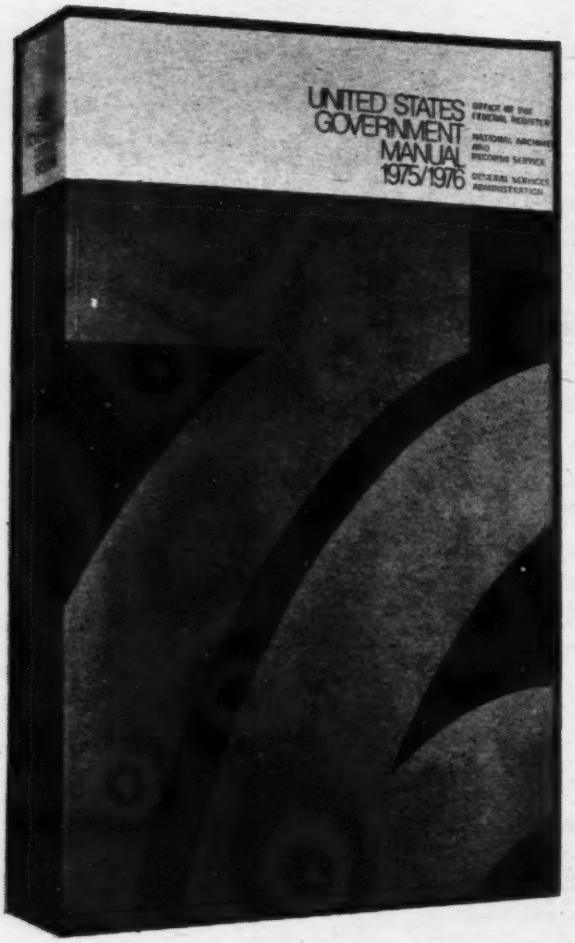
LUNDY R. WRIGHT, Jr.

Sworn to and subscribed before me this 5th day of February, 1976.

JENNIE P. SKELTON,
Notary Public.

My Commission Expires: August 31, 1979.
Washington, D.C.

[FR Doc.76-8949 Filed 3-31-76;8:45 am]



THIS HANDY REFERENCE IS A "MUST" ON YOUR BOOKSHELF!

1975/1976 EDITION

Whatever happened to the Director of Liquidation? (page 693)

Which agencies have programs concerning American Indians? (page 817)

What is SPARS? (page 762)

The answers to these and many more intriguing questions concerning the Federal Government can be found in the *U.S. Government Manual.*

This official guidebook provides useful information about a wide variety of programs and activities within the three branches of Government, including:

- Agency programs, functions, key officials, and a "Sources of Information" section
- Federal regional government system
- A historical reference to Federal agencies and functions
- Bicentennial activities and programs

This handbook is an excellent reference tool for teachers, students, librarians, businessmen, lawyers, and citizens interested in current information about the U.S. Government.

$6.50 per copy
Paper bound, with charts

MAIL ORDER FORM To: Superintendent of Documents, Government Printing Office
Washington, D.C. 20402

Enclosed find $..... (check, money order, or Supt. of Documents coupons). Please send me ..... copies of the UNITED STATES GOVERNMENT MANUAL, 1975/1976, *at $6.50 per copy.*
(Catalog No. GS 4.109:975) (Stock No. 022-003-00910-8)

Please charge this order to my Deposit Account No. .....

Name .....
Street address .....
City and State ..... *ZIP Code* .....

FOR USE OF SUPT. DOCS.
.....Enclosed
.....To be mailed later
.....Subscription
Refund
Coupon refund
Postage
Foreign handling

☆ GPO : 1975—O-58-000